

SPE 19314

Correlations of Interference/Pulse-Test Results With Tiltmeter Studies of Fractures Induced in the Chattanooga Shale

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SPE Members

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ABSTRACT

Natural/induced fracture orientation and permeability anisotropy ($K_x:K_y$) are two critical parameters required for understanding highly fractured anisotropic reservoirs such as the case in the Devonian shales.

A detailed geologic/engineering test was performed on the Chattanooga shale in eastern and southeastern Kentucky. Early results of tiltmeter responses were correlated with pre- and post-stimulation interference and pulse test results. Tiltmeter responses were corrected for uplifts induced by pressure transient during the frac treatment. In addition, corrections were applied to pulse test results for skin and wellbore storage.

Early studies of the pre- and post-stimulation interference tests indicated major permeability trends of N18°E and N32°W, respectively. In addition, a post-stimulation permeability anisotropy of 20:1 was calculated. Results of initial tiltmeter pressure response analyses indicated an induced fracture orientation of N30°E and a possible second orientation of N30°W.

INTRODUCTION

The Devonian shale in the Appalachian Basin has been the subject of a number of studies in the past decade. The objective of those studies was to characterize the shale and evaluate its production potential. Information derived from these studies have been evaluated and extrapolated across the basin to locate areas which may have a high potential to produce gas.

In October 1984, the U.S. Department of Energy/Morgantown Energy Technology Center (DOE/METC) awarded a contract to BDM Engineering Services

Company (BDMESC) for the installation of a Devonian Shale Reservoir Testing Facility and Acquisition of Reservoir Property Measurements from wells in the Michigan, Illinois, and Appalachian Basins. Geologic and engineering data collected through this project, when coupled with data collected by the past Eastern Gas Shale Project (EGSP), will provide a better understanding of the mechanisms and conditions controlling shale gas production.

The intent of this paper is to focus on a series of tests designed to gain a better understanding of the reservoir characteristics of the Chattanooga shale in eastern and southeastern Kentucky. The wells utilized for these tests were drilled in Whitley County, Kentucky. The site, designated as the Offset Well Test Facility (OWTF; Figure 1a), was selected because it was in an area that had not been highly-researched during the earlier EGSP investigations and because it was also an area of immediate interest to oil and gas operators. Significant gas "shows" and initial "open flows" measured in the area indicated that the Chattanooga shale had potential there, but little was known about the reservoir. A cooperative well drilled with Alpha Gas Development had a pre-stimulation open flow of 20 mcfpd (566 m³/day) and a post-stimulation open flow of approximately 280 mcfpd (7927 m³/day). Three wells were drilled in close proximity to this original producing well to establish the Offset Well Test Facility (Figure 1b). Tests conducted at the site included pre- and post-stimulation conventional drawdown and build-up tests, interference tests, pulse tests, and tiltmeter studies of the stimulation test. Data from these tests were combined with pre-stimulation tests such as rock mechanics tests, core analyses, and geological studies to provide an improved understanding of the parameters influencing gas production from the Chattanooga shale in the vicinity of the OWTF site. In addition, the objective

of this study was to acquire information that would help in defining the natural fracture system, the induced fracture orientation, and general induced fracture geometry.

The pre-stimulation pulse tests and the tiltmeter studies were the subject of two SPE papers, #17764 and #18555, respectively. The intent of this paper is to emphasize the results of pre- and post-stimulation interference and pulse tests, correlation of these results with post-stimulation tiltmeter studies, and the natural/induced fracture orientation.

BACKGROUND

Geology

Zielenski and McIver (1982) studied the distribution and interrelationship of Devonian shale organic geochemical data and determined which parameters had exploration significance and could be used to assess gas in-place. Their evaluations did not cover the area of Whitley County because little or no data were available at that time. The area to the immediate east of Whitley County, however, was shown to have a high potential for gas production. Organic carbon content for that area in the Huron shales ranged from 1 to 4 percent and the Thermal Alteration Index was about 2. The organic constituent that predominates in the Huron shales in that area was tasmanites. Based on the amount and type of organic material and the Thermal Alteration Index, Zielenski and McIver (1982) concluded that the Lower Huron rocks in the vicinity of that area where Kentucky, Tennessee and Virginia meet had an excellent gas potential.

The horizon known as the Chattanooga shale is the result of the coalescing of Huron and other shale units which can be identified individually to the east of the site. The thickness of the Devonian shales in southeastern Kentucky also shows a distinct thinning trend from northeast to southwest. In Pike County, near the West Virginia border, it is over 1700 feet (518 m) thick. In McCreary County, just west of Whitley County, the shales are less than 40 feet (12.2 m) thick. Regional isopach maps of the area show an essentially uniform thinning trend, although Fulton⁽¹⁾ (1979) and Potter⁽²⁾ (1978) show closed isopachs on what appear to be isolated thick areas within the shale. Several of those thick zones occur in the Big Sandy gas field located in Knott and Fletcher counties.

The structure in the vicinity of the site does not appear to be very complex on structural maps of the area. It should be noted, however, that there has not been a detailed structural assessment completed for this region. The possibility exists that the Pine Mountain Thrust Fault, located approximately 15 miles (24.14 km) southeast of the site, may have influenced local geology. Pine Mountain is a decollement zone that developed as a subhorizontal shear that extended for great distances only in competent zones and shifted stratigraphic levels upward across short diagonal ramps. Appalachian master decollements such as Pine Mountain generally consist of a series of extensive subhorizontal faults where stratigraphic position changes from lower incompetent

Cambrian rocks on the east to higher incompetent Devonian rocks on the west.

Field Tests/Data Collection

Data from core analysis verified that the shale rock matrix was very low in porosity and permeability; porosity averaging just over one percent and permeability measured at less than 10^{-8} darcies.

Rock mechanics data from core material obtained from the Chattanooga at the test site indicate a moderate primary trend of N30°E for induced fractures based on point-load induced fractures, directional tensile strength maxima, and ultrasonic velocity maxima values.⁽³⁾ A secondary trend of N30°W is indicated by pre-test fractures and directional tensile strength values.

In-situ stress tests were conducted at the site using nitrogen and straddle packer assemblies on tubing. In-situ stress gradients of 0.53 to 0.77 psi/foot (1.2 to 1.8 KPa/m), indicating that induced fractures should be vertical or have a strong vertical component at the site.

Well tests, including drawdown, build-up and pulse tests indicated a low permeability, fractured reservoir in the Chattanooga shale at the site. Reservoir permeability, almost entirely from the natural fracture system, averaged 0.2 millidarcies. Pulse test estimates of fracture porosity ranged from 0.03 to 0.15 percent⁽⁴⁾. Furthermore, tiltmeter responses were measured prior to and after stimulating ONTF #3. These responses were almost all very clear, with the magnitude of the tilt caused by the induced fracture being readily discernible. The pre-corrected tiltmeter data (corrections for uplifts due to pressure transient) indicated a vertical fracture trending N30°E and a N-S trend (SPE #18555).

In addition, downhole video camera surveys revealed several natural fractures within the Chattanooga shale, however, even though the camera was equipped with a magnetic compass, fracture orientation was difficult because only one point of entry was typically observed.

OFFSET WELL TESTING AND ANALYSIS

Single Well Testing

Conventional single well tests were conducted and analyzed. The two primary properties or characteristics normally derived from single well tests are reservoir permeability and wellbore damage, or "Skin", assuming that certain other properties can be readily estimated (porosity, effective thickness, compressibility, etc.).

Pressure build-up data on the four wells producing from the Chattanooga shale were analyzed to determine the various reservoir properties. As a result of applying Horner's technique to the pressure build-up data of RC1 (Figure 2), a permeability and skin of 0.237 md and +34 were calculated respectively. In addition, reservoir simulation was implemented to simulate the build-up history for RC1 (Figure 3). SUGAR-MD, a finite

difference, dual porosity computer model incorporating gas desorption, was used to verify the gas reservoir parameters. The model predicted a bulk reservoir permeability of 0.140 md and a skin factor, S , of +16.5, indicating a damaged wellbore.

Similar pressure build-up analysis techniques were performed on shut-in time pressure data for OWTF 1, OWTF 2, and OWTF 3. In addition to Horner's technique and reservoir simulation, the RHM (Rectangular Hyperbolic Method) technique^(5,6) was utilized to estimate the various reservoir parameters. Tables 1 and 2 list the input parameters and summarizes the results of the single well test analysis for the offset wells using the various analysis techniques⁽⁷⁾.

Worthy of note regarding the permeabilities measured at the individual well sites is the much larger permeability (0.24 md versus 0.06 md) calculated for the Raymond Chandler No. 1 well, even though it is only about 125 feet (38.1 m) from Offset Well No. 1, and no more than 325 feet (99 m) from any of the offsets. This leads one to speculate on the effects of high degrees of lateral heterogeneity and anisotropy. It is possible that the Chandler No. 1 well may have been drilled very close to an intensely-fractured zone resulting in a relatively high calculated value of permeability. The high value for skin would indicate fracture plugging or the absence of fractures near the wellbore.

Interference Tests

A pre-stimulation interference test was also conducted during which pressures were monitored at the site wells while one of the wells was produced and/or shut-in for a period of several days. In December, 1987, Offset Well No. 1 was flowed at a constant rate of 8.5 mscfd while pressures were monitored at Offset Wells No. 1, 2, and 3 and at the Chandler No. 1. After approximately three weeks, Offset Well No. 1 was shut-in and pressures were monitored at all wells during the build-up. Figure 4 shows the pressure responses observed during these tests.

An interference test analysis was performed on the collected data. Table 3 shows the type-curve matching parameters derived for each of the wells in the test. Table 4 exhibits the values for permeability and for the porosity \times viscosity \times compressibility product. Based on these values and using the calculation procedure documented in Sections 9.2 and 9.4 of SPE Monograph 5, Advances in Well Test Analysis, minimum, maximum, and average permeabilities were calculated to be 0.00755 md, 0.990 md, and 0.0865 md, respectively. Maximum permeability direction was calculated to be N18°E, approximately in alignment with the one extension fracture observed in the Chandler No. 1 core and with the coring-induced petal-centerline fractures in the same core (see Figure 5).

A second interference test was conducted using Offset Well No. 3 as the actual well following that well's stimulation by foam fracturing. The results of this test reveal some interesting observations. Not only did the calculated average permeability increase from 0.0865 to 0.364 md (factor of 4X), but the orientation of maximum permeability

was calculated to be N30.6°W compared to N18°E, a difference of almost 50 degrees. The maximum permeability for this test was calculated to be 1.595 md compared to 0.99 md from the previous test, approximately 1.6 times higher. The minimum permeability was calculated to be 0.083 md, or approximately 11 times greater than the 0.00755 md calculated from the pre-stimulation interference test. The ratio of maximum to minimum permeability decreased from approximately 130 to 20. The results of this test are summarized in Tables 5 and 6. A comparison of values between the two tests is shown in Table 7.

Pulse Test

In April 1988, the first pulse test (Pulse Test No. 1) from the Chandler No. 1 well was conducted and consisted of two flow periods of approximately 10 hours each, separated by shut-in periods of approximately 4-1/2 hours. Flow rate for the pulses was a constant 31 mscfd (878 m³/day). Pressures were monitored at each of the offsets. A detailed discussion/analysis of Pulse Test No. 1; test design, field equipment and operation, results and analysis, was the subject of SPE Paper #17764. Table 8 summarizes the results of Pulse Test No. 1.

Prats and Scott⁽⁸⁾ discussed the effect of wellbore storage on the responses of pulse tests and suggested that the relationships that they had developed could probably be extended to sequences of pulses and to cases where pulse duration could not be neglected. They also suggested that wellbore skin effects could probably be taken into account by substituting the effective for the actual wellbore radius into their dimensionless distance and wellbore storage, but warned against trying to apply the technique to situations involving non-radial flow in the responding well.

Because the extent of non-radial flow was unknown, the Prats and Scott technique was applied to the pulse test data in an attempt to improve the quality of the results.

Figures 1 and 2 (Prats and Scott) were utilized to determine the time to reach maximum pressure responses without any wellbore storage effects. In addition, the maximum pressure responses were corrected for wellbore storage effects. Table 9 summarizes the pulse test results after correcting for wellbore storage effects.

In the case of OWTF #3, which was stimulated, an attempt was made to correct for skin effects. An effective wellbore radius was calculated and substituted for the actual wellbore radius. The same procedures used to correct for wellbore storage effects were followed in an attempt to determine a corrected value for permeability and reservoir storage capacity (μC_t) due to skin. Results indicated a new permeability of 0.397 md and a storage capacity value of 1.755×10^{-8} cp-psia⁻¹ compared to a permeability of 0.393 md and a reservoir storage capacity of 1.67×10^{-8} cp-psia⁻¹. Therefore, at low skin improvements the effects on permeability and reservoir storage capacity are minimal.

Tiltmeter Corrections and Analysis

Offset Well No. 3 was stimulated to provide a comparison of limited-entry single-stage fracturing with the 2-stage treatment used to stimulate the Chandler No. 1 well and to provide an opportunity to obtain information concerning the probable orientation of induced fractures in the area. This test and the utilization of tiltmeters for estimating fracture geometry were described in SPE Paper No. 18555.

Prior to the stimulation of Offset Well No. 3, tiltmeters had been installed at the site to monitor earth surface tilts and to estimate fracture geometry. The tilt vectors that resulted from the stimulation are shown in Figure 6. The tilts were analyzed by Hunter Geophysics, Inc., who had provided the field instrumentation and operation, first using a single-fracture source model and later using a dual-fracture model. The single-fracture solution had a minimum "mean square error" for single fracture trending N30°E and dipping 70 degrees to the northwest.

The magnitude of the residual error associated with the single fracture solution was observed to be relatively large, indicating a more complex induced fracture system was probably created. The analysis was extended to a dual-fracture system which reduced the error significantly. The best solution for the dual-fracture model described one of the fractures as trending N35° and vertical while the other fracture was near horizontal trending due north/south and dipping just 10° to the west. In both cases when the single and dual fracture models were used in the analysis, the tiltmeters at sites 5, 6, 7, and 11 were strong contributors to the error and were eliminated from the analysis. Pressure responses were observed in all monitoring wells as seen in Figure 7. Well OW-1 responded first with a gradual but definite increase in pressure that was still increasing 17 hours into the test and well after flowback was begun at the stimulated well. Well OW-2 responded later than OW-1 but with a higher amplitude than either OW-1 or RC-1. The pressure response at RC-1, the most remote well, was similar to that of OW-1 in shape, but lower and having an earlier maximum.

Palmer⁽⁹⁾ suggested that the pressure transient which spreads through the formation during and after a hydraulic fracture treatment will pressurize the formation and induce a certain "swelling". Using poroelastic theory, this swelling and the accompanying uplift at the earth's surface can be estimated. A correction technique, as suggested by Palmer, was implemented and the uplift due to pressure transient from the hydraulic fracture treatment was accounted for. A computer Fortran code was generated for calculating the uplifts, and hence correcting the observed tilt values measured earlier by Hunter Geophysics. Figure 8 exhibits the corrected tilt vectors using Palmer's correction technique.

DISCUSSION AND CONCLUSIONS

The Chattanooga shale at the Whitley County, Kentucky, offset well test facility site was determined to be highly-fractured and faulted. Even so, permeability was very low (less than 0.06 md average) and stimulation by hydraulic fracturing is necessary for commercial production. Porosity is low for the Chattanooga, between one and two percent, and gas content by adsorption is also relatively low because of the low reservoir pressure (approximately 300 psi).

Individual well test results, as exhibited in Table 2, indicate low pre-frac permeability values with a minor improvement in skin at OWTF 2 and OWTF 3.

A comparison of the results of the interference test using OWTF 3 as the active well and RC1 as the observation well versus the corrected pulse test results where RC1 was the pulsed well and OWTF 3 was the observation well, indicated similar permeability values of 0.39 md. These two independent tests confirm the predicted reservoir properties. Furthermore, the significance of the wellbore storage effects on the results of the pulse test indicated a change in permeability values at the observed wells as exhibited in Tables 8 and 9.

In general, fracture diagnostics were inconclusive, but the probable orientation of a hydraulic fracture induced in the Chattanooga shale at the OWTF site is N30-35°E. Rock mechanics tests revealed several possible orientations for induced fractures, but favored the northeasterly trend. Tiltmeter analysis indicated N35°E, but could not resolve tilts that occurred at tiltmeter sites along a northwesterly permeability trend. Initial well interference tests indicated a northeasterly permeability trend, but tests conducted after the stimulation of Offset Well No. 3 showed a northwesterly trend. Permeability anisotropy from the later interference test was calculated to be approximately 20:1.

In conclusion, the results of this extensive study indicated that natural fractures within the shales contain nearly all of the permeability of the reservoir but contain only a small part of the natural gas resource. Clearly, future exploration and development should be directed toward the technologies to detect and/or predict the occurrence of naturally fractured zones and to improve the ability to connect with these zones through such techniques as improved hydraulic fracturing and/or directional drilling.

NOMENCLATURE

C_t	System total compressibility, psi^{-1}
h	Formation thickness, ft
k	Permeability, md
$(P_D)_M$	Dimensionless pressure at match point for type-curve analysis.
$(\Delta P^2)_M$	Pressure-squared change from transient test data at the match point for type curve analysis, psi^2
q	Flow rate, mcfpd
T	Formation temperature, $^{\circ}\text{F}$
$(t_D/r^2D)_M$	Dimensionless time parameter from type curve at the match point for type-curve analysis.
t_L	Time lag used in pulse testing, hrs.
t_M	Time value from transient test data at the match point for type-curve analysis, hrs.
t_p	Flow time, hrs.
r_w	Actual wellbore radius, ft.
S	Skin factor
μ	Viscosity, cp
ϕ	Porosity, fraction
$\phi \mu C_t$	Reservoir storage capacity, cp-psi^{-1}

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TABLE 1

LIST OF INPUT PARAMETERS USED IN THE PRESSURE BUILD-UP ANALYSIS OF THE INDIVIDUAL WELL TESTS AT THE OWTF

PARAMETER	OWTF 1	OWTF 2	OWTF 3
Flow Rate, q (mcfpd)	9	5.8	9.8
Flow Time, t_p (hrs)	503	244	165.5
Total Shut-In Time (hrs)	97	88	142
Thickness, h (ft)	105	104	108
Temperature, T ($^{\circ}\text{F}$)	78	78	78
Viscosity, μ (cp)	0.0102	0.0102	0.0102
Compressibility, C_t (psia^{-1})	0.0042	0.0042	0.0042
Wellbore Radius, r_w (ft)	0.2604	0.2604	0.2604

TABLE 2

RESULTS OF INDIVIDUAL WELL TESTS AT THE OFFSET WELL TEST FACILITY
WHITLEY COUNTY, KENTUCKY

TECHNIQUE	OWTF 1		OWTF 2		OWTF 3	
	K (md)	S	K (md)	S	K (md)	S
Horner	0.072	+3.32	0.044	-1.42	.056	-1.84
Simulation	.06	N/A	0.042	-1.0	.075	-2.8
RHM	0.06	+2.79	0.0111*	+0.7	0.06	-3.0

*The permeability value calculation using the RHM technique is sensitive to the number of points falling within the semi-log region. Since we only have 6 data points within this region, the permeability is not accurately presented.

TABLE 3

TYPE-CURVE MATCHING PARAMETERS FOR INTERFERENCE TEST NO. 1
USING OFFSET WELL NO. 1 AS THE ACTIVE WELL

MATCH VALUES	OBSERVATION WELL NO.		
	CHANDLER #1	OWTF #2	OWTF #3
$(\Delta P^2)_M(\text{psia}^2)$	10,000	10,000	10,000
$(P_D)_M$	3.8	1.3	3.53
$t_M(\text{hr})$	100	100	100
$(t_D/r_D^2)_M$	1.6	7.0	3.1

TABLE 4

RESULTS OF INTERFERENCE TEST NO. 1
USING OFFSET WELL NO. 1 AS THE ACTIVE WELL

PARAMETER	WELL NUMBER		
	CHANDLER #1	OWTF #2	OWTF #3
*Distance, r (ft)	124.2	196.5	211.0
Permeability, K(md)	0.219	0.087	0.228
$\phi\mu C_t$ (dp - psia ⁻¹)	2.34×10^{-7}	8.49×10^{-9}	4.36×10^{-8}
Thickness, h (ft)	121.0	104.0	108.0

* Distance from OWTF #1.

The above values were calculated at: $q = 8.5$ mcf/d
 $\mu = 0.0102$ Cp
 $T = 538^\circ\text{R}$
 $Z = 0.9588$

TABLE 5

TYPE-CURVE MATCHING PARAMETERS FOR INTERFERENCE TEST NO. 2
USING HYDRAULICALLY-FRACTURED OFFSET WELL #3 AS THE ACTIVE WELL

MATCH VALUES	OBSERVATION WELL NO.		
	CHANDLER #1	OWTF #2	OWTF #3
$(\Delta P^2)_M(\text{psia}^2)$	100,000	100,000	100,000
$(P_D)_M$	5.8	4.4	5.2
$t_M(\text{hr})$	1,000	1,000	1,000
$(t_D/r_D^2)_M$	74	24.5	55

TABLE 6

RESULTS OF INTERFERENCE TEST NO. 2
USING HYDRAULICALLY-FRACTURED OFFSET WELL NO. 3 AS THE ACTIVE WELL

PARAMETERS	CHANDLER #1	OWTF #1	OWTF #2
*Distance, r(ft)	315.5	211	111
Permeability, K(md)	0.394	0.344	0.410
$\phi\mu C_t$ (cp-psia ⁻¹)	1.41×10^{-8}	8.32×10^{-8}	15.9×10^{-8}
Thickness, h(ft)	121	105	104

* Distance from OWTF #3.

The above values were calculated at: $q = 100$ mcf/d
 $\mu = 0.0102$ cp
 $T = 538^\circ\text{R}$
 $Z = 0.9588$

TABLE 7

COMPARISON OF RESULTS OF INTERFERENCE TESTS NO. 1 AND 2
AT THE OFFSET WELL TEST FACILITY, WHITLEY COUNTY, KENTUCKY

	TEST NO. 1 (OFFSET WELL #1 ACTIVE)	TEST NO. 2 (OFFSET WELL #3 ACTIVE)
Maximum Permeability (md)	0.9895	1.595
Minimum Permeability (md)	0.0075	0.083
Average Permeability (md)	0.0865	0.364
$\phi\mu C_t$ (cp-psia ⁻¹)	5.43×10^{-8}	7.79×10^{-8}
Direction of Max. Perm.	N18°E	N31.6°W
Ratio Max/Min Perm.	131	19.2

TABLE 8

OBSERVED PULSE TEST RESULTS
PULSE TEST NO. 1 - RC 1 PULSED WELL

RESPONDING WELL	OWTF 1	OWTF 2	OWTF 3
Time Lag, t_L (hrs)	2.78	3.08	2.23
ΔP pseudo Pressure, psi^2/cp	15,870	33,300	27,800
Permeability, md	0.81	0.32	0.66
Distance from Pulsed Well (ft)	124.2	262.4	315.1

TABLE 9

CORRECTED PULSE TEST RESULTS
DUE TO WELLBORE STORAGE EFFECTS
PULSE TEST NO. 1 - RC 1 PULSED WELL

RESPONDING WELL	OWTF 1	OWTF 2	OWTF 3
Time Lag, t_L (hrs)	1.21	2.8	1.89
ΔP pseudo Pressure, psi^2/cp	24,797	33,636	30,889
Permeability, md	0.92	0.21	0.393
Reservoir Storage Capacity ($\text{cp}\cdot\text{psi}^{-1}$)	16.93×10^8	1.88×10^{-8}	1.67×10^8

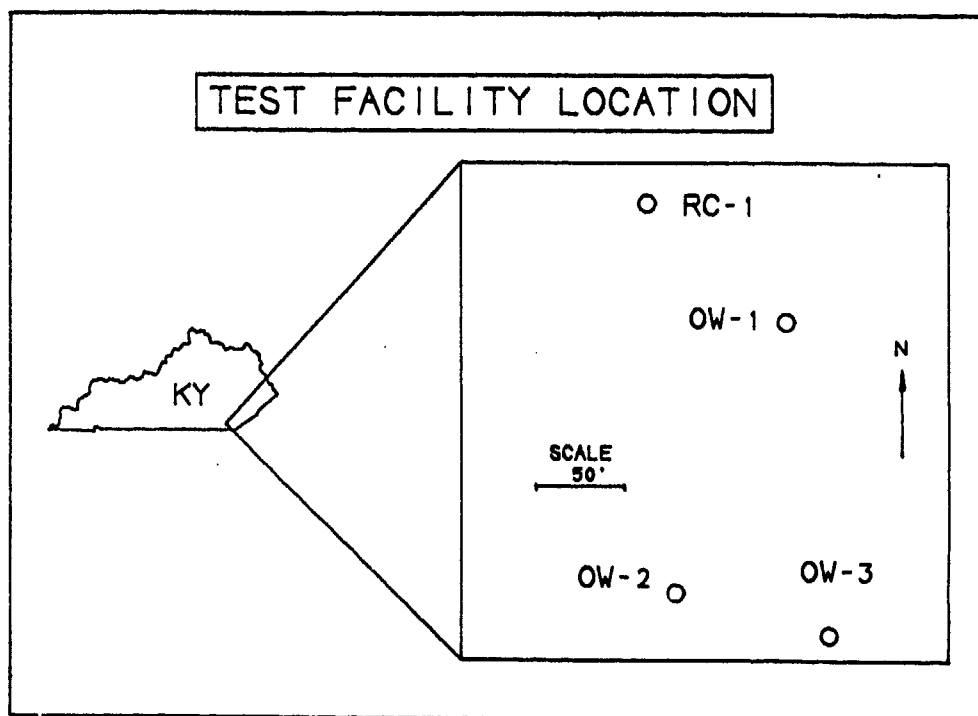


Figure 1a - Site of the OMTF Study Area

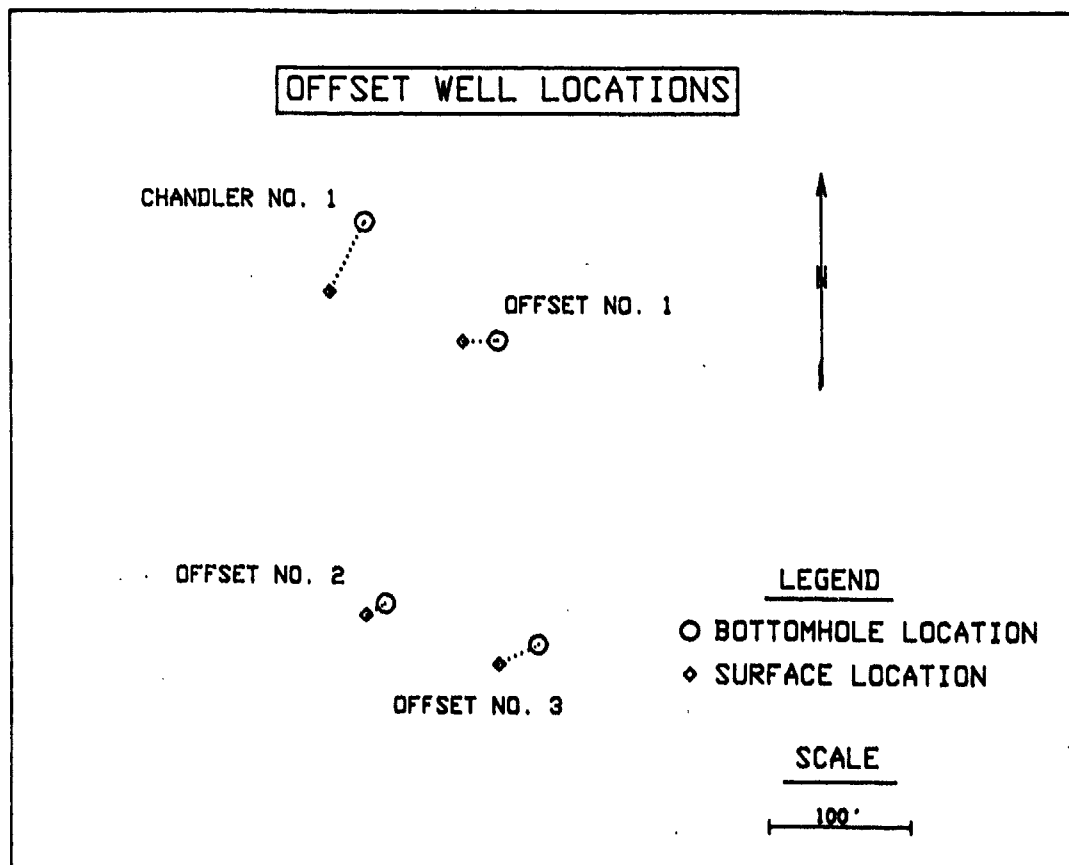


Figure 1b - Well Location Map for the OMTF Site

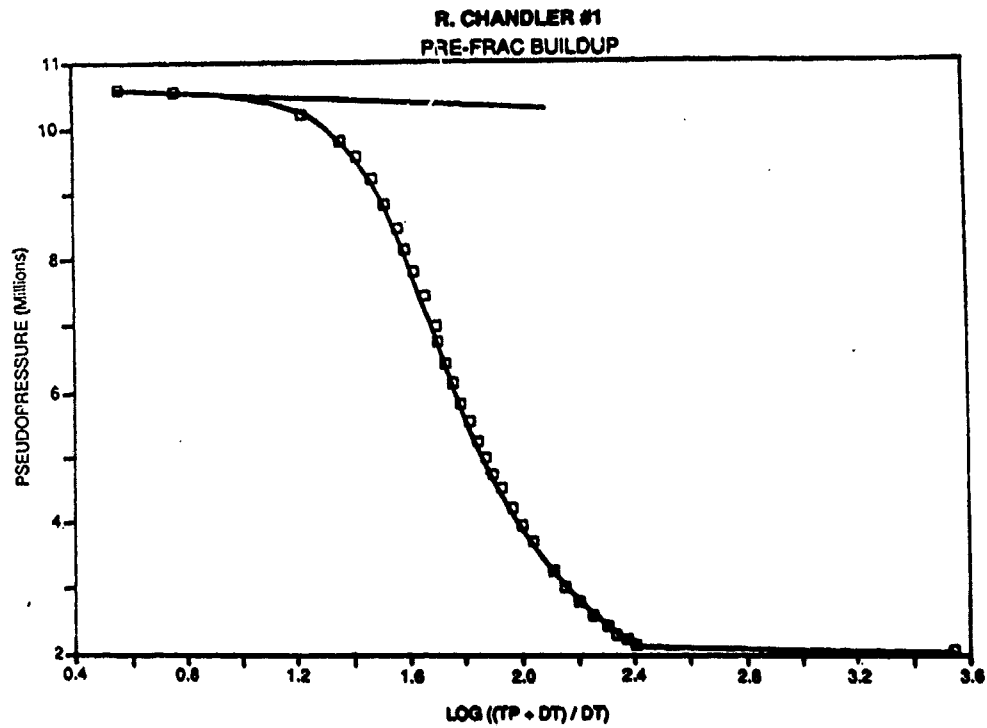


Figure 2 -- Example of Pre-frac Build-up Curve (Horner Time Semi-log Plot)

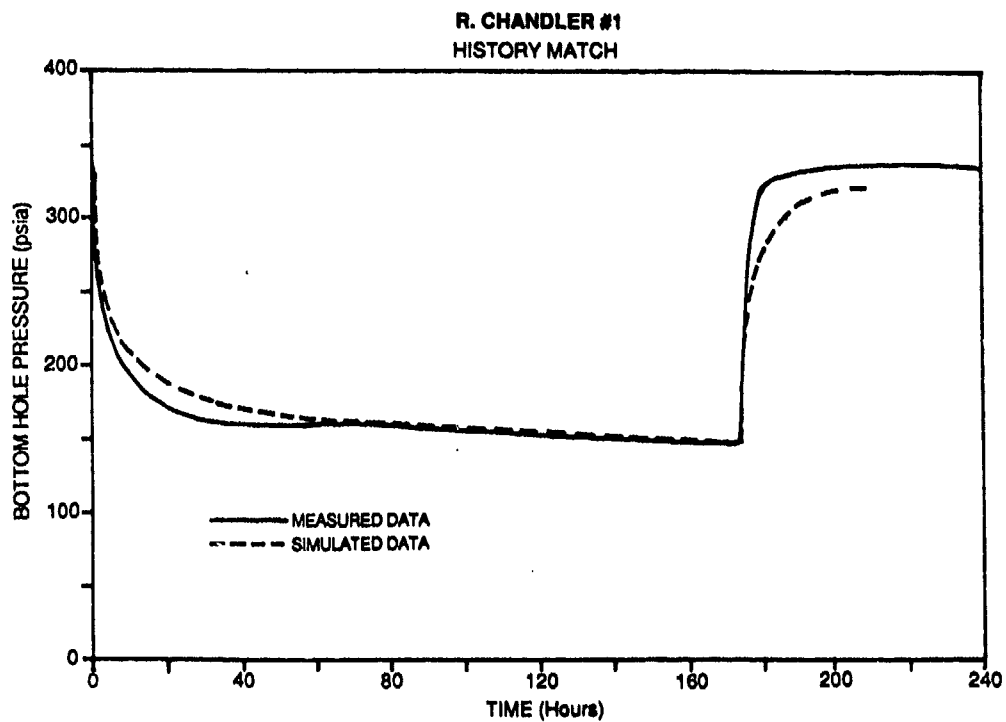


Figure 3 - Reservoir Simulation Results for R. Chandler #1

OWTF COMMUNICATIONS TEST

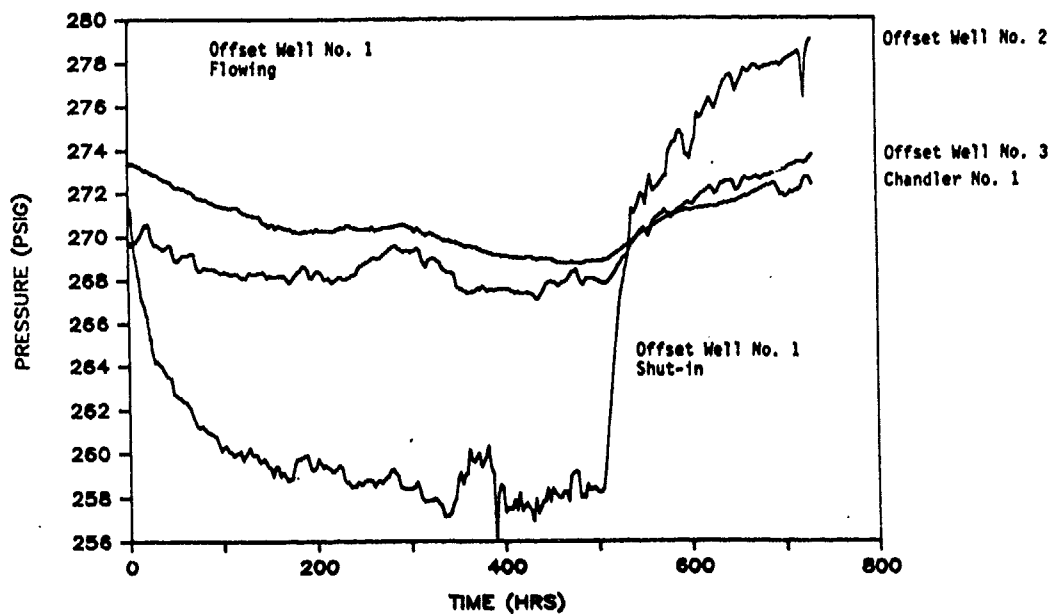


Figure 4- -- Interference Test Pressure Response During Flow and Shut-in Periods for Offset Well No. 1

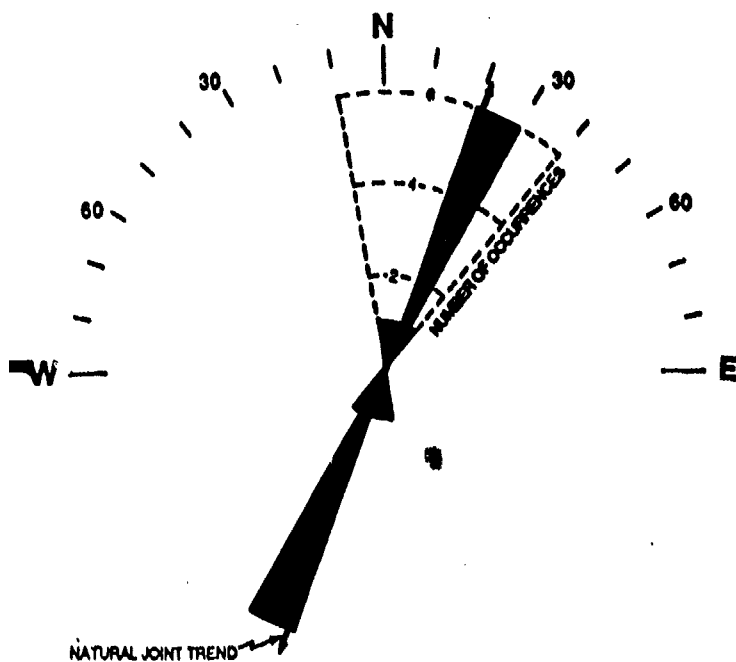


Figure 5- Coring-Induced Petal Centerline Strike Directions Including a Single Natural Joint Trend for the R. Chandler No. 1

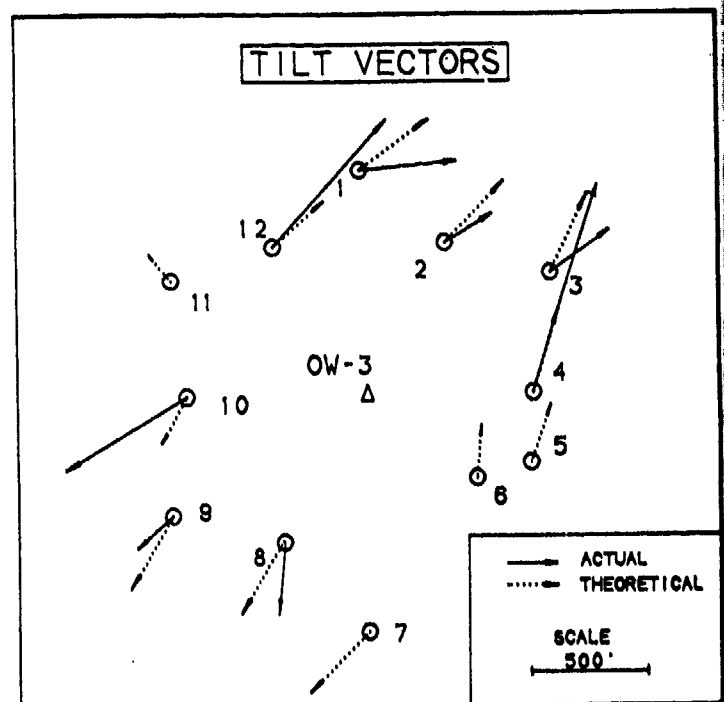


Figure 6 - Observed Tiltmeter Results Due to Fracturing OWTF 3

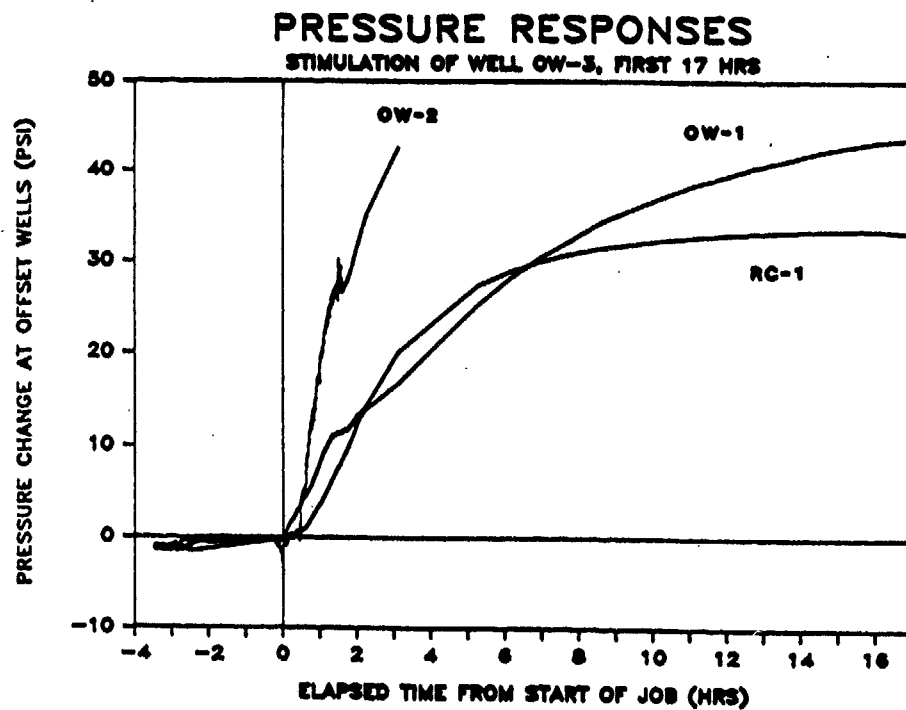


Figure 7 -- Pressure Responses at Monitoring Wells During and Following Stimulation of Offset Well No. 3, First 17 Hours

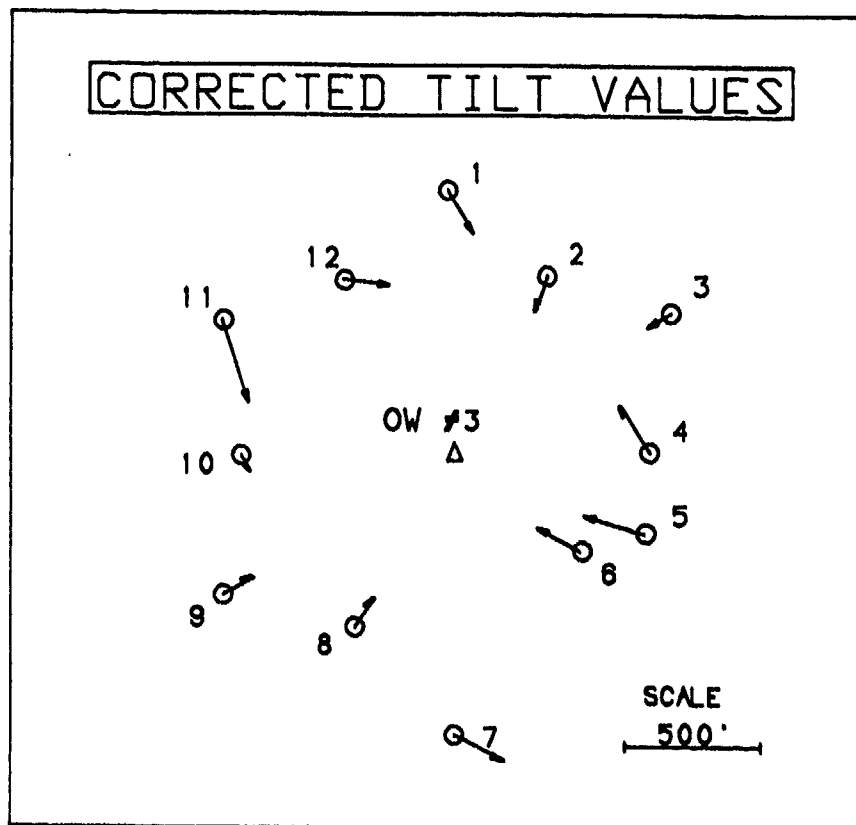


Figure 8 - Corrected Tiltmeter Values as a Result of Fracturing OWTF No. 3